BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2021-1-E

In the Matter of Annual Review of Base Rates for Decrease in Residential and Lighting Customer Fuel Costs and for Increase in General Service Non-Demand and General Service Demand Customer Fuel Costs for Duke Energy Progress, LLC	)))))))	**DIRECT TESTIMONY OF** **BRETT PHIPPS FOR** **DUKE ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brett Phipps. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Managing Director, Fuel Procurement, for Duke Energy Corporation ("Duke Energy"). In that capacity, I directly manage the organization responsible for the purchase and delivery of coal and natural gas to Duke Energy's regulated generation fleet, including Duke Energy Progress, LLC ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC") (collectively, the "Companies"). In addition to fuels, I also supervise the procurement of all reagents.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree in Chemistry from Marshall University. I began in the mining industry in 1993 where I held various roles associated with surface mining operations. I joined Progress Energy in 1999, holding roles in terminal operations and sales and marketing for the unregulated business. I transitioned to the regulated utility in 2005, where I worked in various fuels procurement functions and leadership roles. I joined Duke Energy in July 2012 and am currently Managing Director, Fuels Procurement. I am a member of the American Coal Council, The Coal Institute, the Lexington Coal Exchange, and Southern Gas Association.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified before the Public Service Commission of South Carolina ("Commission") in

DEP's 2017 and 2019 fuel and environmental cost proceedings in Docket No. 2017-1-E and 2019-1-E, as well as in DEC's 2017 and 2019 fuel and environmental cost proceedings in Docket No. 2017-3-E and Docket No. 2019-3-E.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe DEP's fossil fuel purchasing practices, provide actual fossil fuel costs for the period March 1, 2020 through February 28, 2021 ("review period") versus March 1, 2019 through February 29, 2020 ("prior review period"), and describe changes forthcoming for the period July 1, 2021 through June 30, 2022 ("billing period").

Q. YOUR TESTIMONY INCLUDES TWO EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Phipps Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, and Phipps Exhibit 2, which summarizes total monthly natural gas purchases and monthly contract and spot coal purchases during the review period and the prior review period.

Q. PLEASE PROVIDE A SUMMARY OF DEP'S FOSSIL FUEL PROCUREMENT PRACTICES.

A. A summary of the Company's fossil fuel procurement practices is set out in Phipps Exhibit 1.

Q. HOW DOES THE COMPANY OPERATE ITS PORTFOLIO OF GENERATION ASSETS TO RELIABLY AND ECONOMICALLY SERVE ITS CUSTOMERS?

A. Both DEP and DEC utilize the same process to ensure that the assets of the Companies are reliably and economically available to serve their respective customers. To that end, both companies consider factors that include, but are not limited to, the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at the generating units, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their customers.

Q. PLEASE DESCRIBE THE COMPANY'S DELIVERED COST OF COAL AND NATURAL GAS DURING THE REVIEW PERIOD.

A. The Company's average delivered cost of coal per ton for the review period was $96.35 per ton, compared to $85.85 per ton in the prior review period, representing an increase of approximately 12%. The cost of delivered coal includes an average transportation cost of $39.38 per ton in the review period, compared to $31.03 per ton in the prior review period, representing an increase of approximately 27%. The cost of delivered coal also includes $12.5 million in costs associated with the mitigation of coal contract obligations related to COVID-19 load losses, as is described in more detail below. The Company's average price of gas purchased for the review period was $3.72 per Million British Thermal Units ("MBtu"), compared to $3.80 per MBtu in the prior review period, representing a decrease of 2%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEP's coal burn for the review period was 3.4 million tons, compared to a coal burn of 3.8 million tons in the prior review period, representing a decrease of 11%. The Company's natural gas burn for the review period was 158.7 million MBtu compared to a gas burn of 166.6 million MBtu in the prior review period, representing a decrease of 5%.

As a result of load reduction from the COVID-19 pandemic, extremely low natural gas prices, and mild winter weather, the Company experienced a significant shift in generation from coal to natural gas. The COVID-19 pandemic had an unprecedented and unanticipated impact on forecasted spring and summer load in 2020, which in turn reduced coal demand and required inventory mitigation beyond the Company's typical no-cost mitigation measures. Influenced by the operational realities from the pandemic, DEP burned significantly less coal than anticipated, and customers benefited from greater utilization of lower-cost natural gas.

Given the reduction in actual and forecasted coal usage for the balance of 2020, the Company was required to evaluate alternatives to reduce its coal contract obligations for 2020 that exceeded its consumption and storage capabilities. The Company exercised and exhausted its rights to flex down contractual obligations, defer tons, and optimize off-site storage opportunities at no additional cost to the customer in order to address the excess coal due to significant declines in demand related to COVID-19 related shutdowns. After exhausting all of its no-cost contract mitigation options, it was necessary to determine whether to force-run coal generation out of economic merit or to maximize customers savings by burning natural gas while negotiating to buy out of the remaining balance of the Company's excess 2020 coal obligations. The Company determined through its production cost analysis that pursuing contractual buyouts would result in projected customer savings of approximately $22 million as compared with force running coal generation, and this is the course of action the Company implemented.

Q. PLEASE DESCRIBE THE LATEST TRENDS IN COAL AND NATURAL GAS MARKET CONDITIONS.

A. Coal markets continue to be distressed, and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers due to declining demand for coal stemming from accelerated coal retirements and overall declines in coal generation demand resulting from the impacts of COVID-19 economic shutdowns in 2020; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (4) changing demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening access to investor financing coupled with deteriorating credit quality is increasing the overall costs of financing for coal producers; and, (7) corrections in production levels in an attempt to bring coal supply in balance with demand.

With respect to natural gas, the nation's natural gas supply has grown significantly over the last several years and producers continue to enhance production techniques, enhance efficiencies, and lower production costs. Natural gas prices are reflective of the dynamics between supply and demand factors, and in the short term, such dynamics are influenced primarily by seasonal weather demand and overall storage inventory balances. While there continues to be adequate natural gas production capacity to serve increased market demand, pipeline infrastructure permitting and regulatory process approval efforts are challenged due to increased reviews and interventions, which can delay and change planned pipeline construction and commissioning timing. Specifically, cancellation of the Atlantic Coast Pipeline which was terminated July 5, 2020, will limit the Company's access to low cost natural gas resources.

Over the longer term planning horizon, natural gas supply is projected to continue to increase while the pipeline infrastructure needed to move the growing supply to meet demand related to power generation, liquefied natural gas exports and pipeline exports to Mexico is highly uncertain.

Q. WHAT ARE THE PROJECTED COAL AND NATURAL GAS CONSUMPTIONS AND COSTS FOR THE BILLING PERIOD?

A. DEP's current coal burn projection for the billing period is 1.9 million tons compared to 3.4 million tons consumed during the review period. DEP's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. Combining coal and transportation costs, DEP projects average delivered coal costs of approximately $84.89 per ton for the billing period compared to $96.35 per ton in the review period. This includes an average projected total transportation cost of $42.46 per ton for the billing period, compared to $39.38 per ton in the review period. This projected delivered cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal DEP is able to consume; (3) performance of contract deliveries by suppliers and railroads which may not occur despite DEP's strong contract compliance monitoring process; (4) changes in transportation rates; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

DEP's current natural gas burn projection for the billing period is approximately 151.3million MBtu, compared to 158.7 million MBtu consumed during the review period. The current average forward Henry Hub price for the billing period is $2.82 per million MBtu compared to $2.18 per million MBtu in the review period. Projected natural gas burn volumes will vary based on factors such as, but not limited to, changes in actual delivered fuel costs and weather driven demand.

Q. WHAT STEPS IS DEP TAKING TO MANAGE PORTFOLIO FUEL COSTS?

A. The Company continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes, while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost effective manner. With respect to coal procurement, the Company's procurement strategy includes (1) having an appropriate mix of contract and spot purchases for coal; (2) staggering coal contract expirations in order to limit exposure to market price changes; and (3) diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. The Company conducts spot market solicitations throughout the year to supplement term contract purchases, taking into account changes in projected coal burns and existing coal inventory levels.

The Company has implemented natural gas procurement practices that include periodic Request for Proposals and shorter-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply. These procurement practices include contracting for volumetric optionality in order to provide flexibility in responding to changes in forecasted fuel consumption. DEP continues to maintain a short-term natural gas hedging plan to manage fuel cost risk for customers via a disciplined, structured execution approach. DEP continues to monitor and make adjustments as necessary to its natural gas hedging program.

Lastly, the Company procures long-term firm interstate and intrastate transportation to provide natural gas to its generating facilities. Given the Company's limited amount of contracted firm interstate transportation, the Company purchases shorter term firm interstate pipeline capacity as available from the capacity release market. The Company's firm transportation ("FT") provides the underlying framework for the Company to manage the natural gas supply needed for reliable cost-effective generation. First, it allows the Company access to lower cost natural gas supply from Transco Zone 3 and Zone 4 and the ability to transport gas to Zone 5 for delivery to the Carolinas' generation fleet. Second, the Company's FT allows it to manage intraday supply adjustments on the pipeline through injections or withdrawals of natural gas supply from storage, including on weekends and holidays when the gas markets are closed. Third, it allows the Company to mitigate imbalance penalties associated with Transco pipeline restrictions, which can be significant. The Company's customers receive the benefit of each of these aspects of the Company's FT: access to lower cost gas supply, intraday supply adjustments at minimal cost, and mitigation of punitive pipeline imbalance penalties.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Duke Energy Progress, LLC Fossil Fuel Procurement Practices

Coal

- Near and long-term coal consumption is forecasted based on inputs such as load projections, fleet maintenance and availability schedules, coal quality and cost, non-coal commodity and emission prices, environmental permit and emissions constraints, projected renewable energy production, and wholesale energy imports and exports.
- Station and system inventory targets are developed to provide generational reliability, insulation from short-term market volatility, and adaptability to evolving coal production and transportation conditions. Inventories are monitored continuously.
- On a continuous basis, existing purchase commitments are compared with consumption and inventory requirements to determine changes in supply needs.
- All qualified suppliers are invited to participate in Request for Proposals to satisfy additional supply needs.
- Spot market solicitations are conducted on an on-going basis to supplement existing purchase commitments.
- Contracts are awarded based on the highest customer value, considering factors such as price, quality, transportation, reliability and flexibility.
- Delivered coal volume and quality are monitored against contract commitments. Coal and freight payments are calculated based on certified scale weights and coal quality analysis meeting ASTM standards as established by ASTM International.

Gas

- Near and long-term natural gas consumption is forecasted based on inputs such as load projections, commodity and emission prices, projected renewable energy production, and fleet maintenance and availability schedules.
- Physical procurement targets are developed to procure a cost effective and reliable natural gas supply.
- Natural gas supply is contracted utilizing a portfolio of long term, short term, spot market and physical call option agreements
- Short-term and long-term Requests for Proposals and market solicitations are conducted with potential suppliers, as needed, to procure the cost competitive, secure, and reliable natural gas supply, firm transportation, and storage capacity needed to meet forecasted gas usage.
- Short-term and spot purchases are conducted on an on-going basis to supplement term natural gas supply.
- On a continuous basis, existing purchases are compared against forecasted gas usage to determine changes in supply and transportation needs.
- Natural gas transportation for the generation fleet is obtained through a mix of long-term firm transportation agreements, and shorter-term pipeline capacity purchases.
- A targeted percentage of the natural gas fuel price exposure is managed via a rolling 60-month structured financial natural gas hedging program.

- Through the Asset Management and Delivered Supply Agreement between Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC implemented on January 1, 2103, DEC serves as the designated Asset Manager that procures and manages the combined gas supply needs for the combined Carolinas gas fleet.

Fuel Oil

- No. 2 fuel oil is burned primarily for initiation of coal combustion (light-off at steam plants) and in combustion turbines (peaking assets).
- All No. 2 fuel oil is moved via pipeline to applicable terminals where it is then loaded on trucks for delivery into the Company's storage tanks. Because oil usage is highly variable, the Company relies on a combination of inventory, responsive suppliers with access to multiple terminals, and trucking agreements to manage its needs. Replenishment of No. 2 fuel oil inventories at the applicable plant facilities is done on an "as needed basis" and coordinated between fuel procurement and station personnel.
- Formal solicitations for supply may be conducted as needed with an emphasis on maintaining a network of reliable suppliers at a competitive market price in the region of our generating assets.

DUKE ENERGY PROGRESS
Summary of Coal Purchases
Twelve Months Ended February 2020 & 2021
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales(Tons)	Total (Tons)
1	March 2020	63,516.00	25,179	88,695
2	April	205,573	(6,844)	198,729
3	May	37,639	(11,647)	25,992
4	June	13,060	(5,985)	7,075
5	July	205,293	(1,250)	204,043
6	August	280,431	-	280,431
7	September	292,974	-	292,974
8	October	281,434	12,427	293,861
9	November	244,691	24,851	269,542
10	December	293,006	-	293,006
11	January 2020	147,303	74,534	221,837
12	February	195,798	49,231	245,029
13	**Total** (Sum L1:L12)	**2,260,718**	**160,496**	**2,421,214**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales(Tons)	Total (Tons)
14	March 2019	402,153	24,070	426,223
15	April	323,887	130,272	454,159
16	May	274,199	114,353	388,552
17	June	264,904	128,425	393,329
18	July	302,124	103,008	405,132
19	August	242,562	138,879	381,441
20	September	250,947	122,036	372,983
21	October	328,185	0	328,185
22	November	423,513	12,789	436,302
23	December	388,247	0	388,247
24	January 2019	292,138	51,142	343,280
25	February	0	0	0
26	**Total (Sum L14:L25)**	**3,492,859**	**824,974**	**4,317,833**

DUKE ENERGY PROGRESS
Summary of Gas Purchases
Twelve Months Ended February 2020 & 2021
MBTUs

Line No.	Month	MBTUs
1	March 2020	12,804,810
2	April	8,048,333
3	May	10,825,017
4	June	13,181,648
5	July	17,709,068
6	August	15,791,691
7	September	12,396,157
8	October	11,455,652
9	November	11,887,528
10	December	17,038,827
11	January 2021	15,211,307
12	February	12,301,205
13	**Total (Sum L1:L12)**	**158,651,243**

Line No.	Month	MBTUs
14	March 2019	12,831,035
15	April	12,297,990
16	May	8,937,450
17	June	12,847,001
18	July	15,401,771
19	August	15,584,187
20	September	14,570,973
21	October	13,869,892
22	November	14,862,032
23	December	13,958,980
24	January 2020	15,791,889
25	February	15,640,418
26	**Total (Sum L14:L25)**	**166,593,618**